Charles A. Castle
Associate General Counsel

Duke Energy Corporation
550 South Tryon Street
Charlotte, NC 28202

Mailing Address:
DEC45A / P.O. Box 1321
Charlotte, NC 28201

o: 704.382.4499
f: 980.373.8534
alex.castle@duke-energy.com

March 17, 2015

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk / Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29211

RE: Application of Duke Energy Carolinas, LLC. to Establish a Distributed Energy Resource Program
Docket No. 2015-55-E

Dear Mrs. Boyd:

Enclosed for filing on behalf of Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or "the Company"), please find the Direct Testimony and Exhibits of Emily O. Felt, Jose I. Merino, and Kim H. Smith in the above-referenced matter.

The Company respectfully requests that the exhibits of Jose I. Merino be accepted by the Commission under seal and maintained as confidential pursuant to Order No. 2005-226. Company witness Merino's exhibits contain certain confidential information relating to internally-derived installed cost estimates and valuation models for customer and Company-owned generation that is proprietary and commercially sensitive to Duke Energy Carolinas. The Company requests that the Commission grant the Company's request for confidential treatment pursuant to 26 S.C. Code Ann. Regs. 103-804(S)(2) (2014 Supp.) and protect this information from public disclosure.

By copy of this letter, I am serving all parties of record via electronic mail. Please contact me if you have any questions concerning this filing.

Sincerely,

Charles A. Castle
Associate General Counsel

CAC/gf
Attachment
Cc: All parties of record

STATE OF SOUTH CAROLINA
BEFORE THE PUBLIC SERVICE COMMISSION
DOCKET NO. 2015-55-E

Application of Duke Energy Carolinas, LLC to Establish A Distributed Energy Resource Program	)))	CERTIFICATE OF SERVICE

I hereby certify that the Direct Testimony and Exhibits of Emily O. Felt, Jose I. Merino and Kim H. Smith on behalf of Duke Energy Carolinas, LLC, have been served by electronic mail (e-mail), hand delivery or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record set forth below.

Andrew M. Bateman, Counsel
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
abateman@regstaff.sc.gov

Shannon Bowyer Hudson, Counsel
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
shudson@regstaff.sc.gov

This the 17th day of March, 2015.

Charles A. Castle
Associate General Counsel
Duke Energy Corporation
DEC45A/550 South Tryon St.
Charlotte, NC 28202
704.382.4499
alex.castle@duke-energy.com

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2014-55-E

In the Matter of:	)	
	)	
Application of	)	**DIRECT TESTIMONY OF**
Duke Energy Carolinas, LLC to	)	**EMILY O. FELT**
Establish a Distributed Energy	)	**ON BEHALF OF DUKE ENERGY**
Resource Program	)	**CAROLINAS, LLC.**
	)	
	)	

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Emily O. Felt and my business address is 400 South Tryon St., Charlotte, North Carolina, 28202.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION WITH THE COMPANY?

A. I am a Manager of Strategy and Policy in the Distributed Energy Resources group at Duke Energy Corporation.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I received a Bachelor of Arts degree from Stanford University and a Master of Public Administration from Harvard University. I serve on the Board of Directors of Palmetto Clean Energy. I joined Duke Energy Corporation in 2007 as a business development manager. In 2010, I moved to the Company's renewable energy strategy and compliance group where I was accountable for Duke Energy Carolinas' compliance with the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard. In 2012, I moved into a strategic policy role within the same group.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AS MANAGER OF STRATEGY AND POLICY ?

A. I am responsible for the development and execution of strategies related to distributed energy resources for Duke Energy's South Carolina franchises, Duke Energy Carolinas, LLC ("DEC," "Company" and "Applicant") and Duke Energy Progress, Inc. ("DEP"). This includes evaluation of legislation, regulatory initiatives, customer programs, and other issues related to the implementation of Act 236, the South Carolina Distributed Energy Resource Act of 2014 (the "Act").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the application of DEC to establish a Distributed Energy Resource ("DER") Program and to demonstrate how the proposed portfolio of distributed energy resource initiatives will fulfill the goals of Act 236, specifically, to "promote the establishment of a reliable, efficient, and diversified portfolio of distributed energy resources for the State."

II. THE PURPOSE FOR THE CURRENT PROCEEDING

Q. PLEASE DESCRIBE THE PURPOSE OF THE CURRENT PROCEEDING.

A. The purpose of this proceeding is to further the goals of Act 236 through the establishment and execution of a DER Program. The Act permits an electrical utility to apply to the Public Service Commission of South Carolina ("Commission") for approval to participate in a DER Program. After conducting a hearing on the application, the Commission may approve such application if the applicant demonstrates that the program will further the goals of Act 236 as set forth in S.C. Code § 58-39-110.

Q. ARE THERE SPECIFIC GUIDELINES OR PARAMETERS TO BE FOLLOWED BY A DER APPLICANT?

A. Yes, a DER Program application must contain specific, substantive elements outlined in S.C. Code §58-39-130(A)(1), such as a statement of goals, proposed customer programs, costs, benefits, description of barriers to deployment of DER, etc. Pursuant to S.C. Code §58-39-130 (C), the applicant utility must also demonstrate that its programs will result in the development of installed South Carolina-sited renewable capacity equaling two percent (2%) of the Company's estimated average South Carolina retail peak demand over the previous five year period, which is approximately 84 megawatts ("MW") for DEC.

III. <u>THE COMPONENTS OF THE APPLICATION</u>

Q. PLEASE DESCRIBE THE MAJOR COMPONENTS OF THE APPLICATION.

A. The major components of the Company's DER Application are descriptions, costs, and benefits of initiatives designed to increase the capacity of solar generation located in its service area from 1,300 kilowatts ("kW"), or 1.3 MW, as of January 1, 2015, to approximately 84,000 kW, or 84 MW, by January 1, 2021. The Company proposes to meet half of the total capacity target through the introduction of three new customer offers: the DER net energy metering ("NEM") Incentive, a Solar Rebate Program, and a Shared Solar Program. These programs are designed to incent residential and non-residential customers to invest in or lease these facilities, both on- and off-premise. Also included in the Company's application is a description of the Company's plan to meet the balance of the capacity requirement through procurement of renewable energy from large-scale solar facilities located in South Carolina.

Q. PLEASE DESCRIBE THE COMPANY'S PLAN TO PROVIDE AN DER NEM INCENTIVE.

A. The Company proposes to provide an DER NEM Incentive to eligible NEM customer-generators that will enable the customer to enjoy full retail credit for their net-metered solar generation for a period of time, as defined in the Settlement Agreement in Docket No. 2014-246-E ("Settlement Agreement"). Thus, the Company's NEM offer to customers will remain functionally the same as it had been before the passage of Act 236.

It is important to note that this incentive is embedded and will not be readily apparent to participating NEM customers. The DER NEM Incentive will *not* be separately stated on the NEM customer's bill, but it will be calculated pursuant to the methodology approved by the Commission in Docket No. 2014-246-E, and will be treated and recovered as an incremental cost as defined in S.C. Code § 58-39-140.

Q. PLEASE DESCRIBE THE COMPANY'S PLAN TO PROVIDE SOLAR REBATES.

The Solar Rebate Program is a new tariff designed to encourage homeowners and businesses to install solar energy systems on-site by providing assistance with the capital requirements of a solar investment. The enticement is in the form of a dollar-per-watt rebate provided to the customer upon completion of the solar energy system installation. Customers who install solar energy systems (up to one MW in size) may apply for the rebate. Qualified residential customers will receive $1.00 per watt or $1,000 per kW. Qualified non-residential customers would receive $0.75 per watt, or $750 per kW.

As an example, if a qualified residential customer were to spend the approximately $20,000 required to install 5 kW of rooftop solar PV capacity, upon proof of completion and inspection, the Company would provide a rebate check in the amount of $5000 to the customer. Customers may apply the rebate to a purchase or lease of solar energy systems. Customers who receive the rebate may combine the rebate with the Company's NEM tariff, or with the Company's standard power purchase agreement ("PPA") in South Carolina, Schedule PP. The Company has proposed to make the Solar Rebate Program available retroactively for solar energy facilities constructed after January 1, 2015, consistent with the terms of the Settlement Agreement.

Q. PLEASE DESCRIBE THE COMPANY'S PLAN TO PROVIDE ACCESS TO SOLAR ENERGY THROUGH A SHARED SOLAR PROGRAM.

A. The Company proposes a third customer solar initiative, a Shared Solar program option whereby multiple retail customers may subscribe to and share in the economic benefits of one renewable energy facility. Although it is designed for customers holding tax-exempt status, such as houses of worship, schools, universities, military installations, and government offices, this option will be accessible to a wide array of eligible residential or non-residential customers. The Company expects the program to have strong appeal to residential and commercial customers who rent or lease their premise, to residential customers who reside in multifamily housing units or even shaded housing, and to residential customers for whom the relatively high up-front costs of solar PV make the technology unattainable. The shared generating assets will be located throughout the Company's South Carolina retail service area, built in 1,000 kW increments, and ground-mounted rather than roof-mounted.

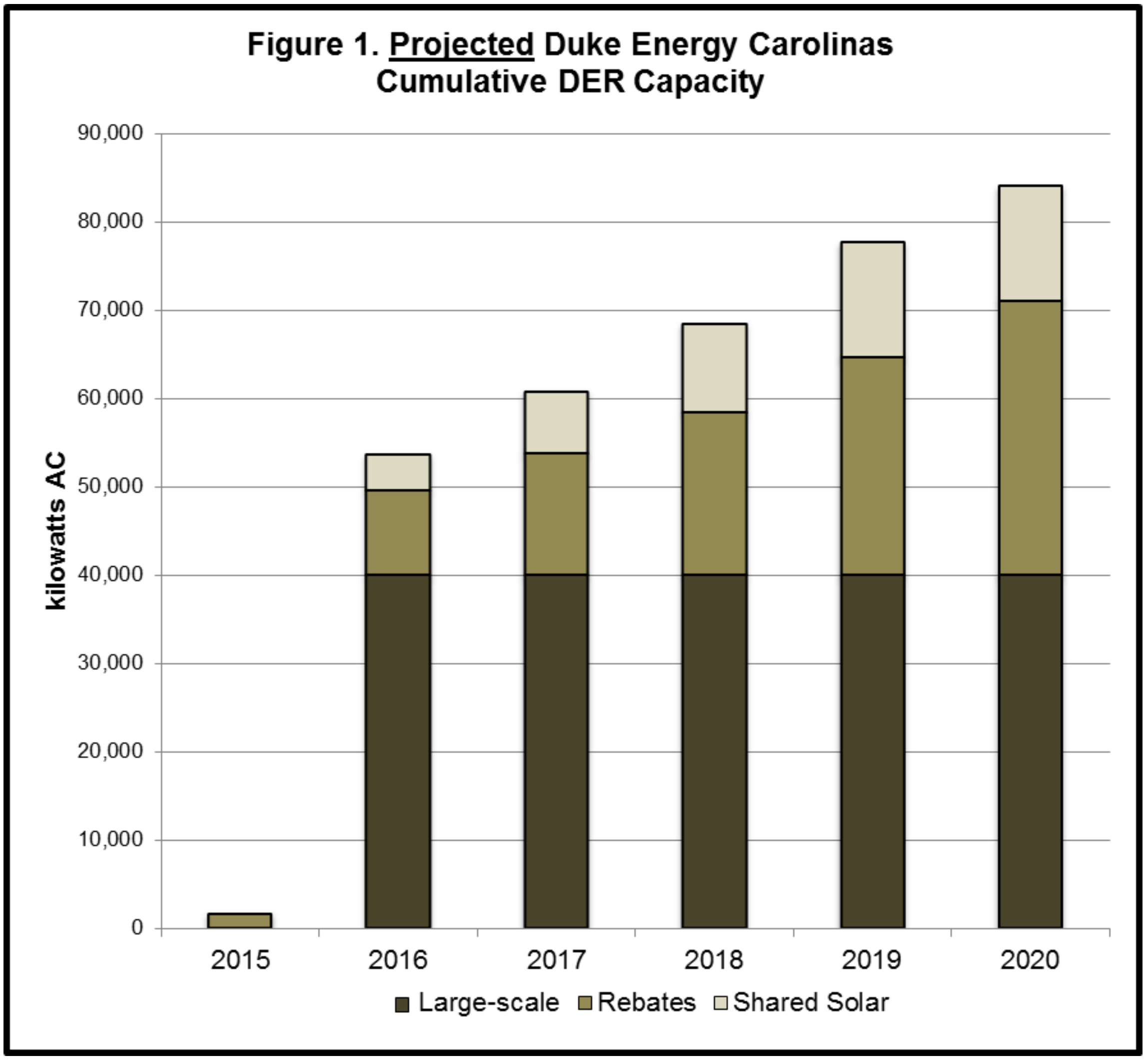
Within 90 days of Commission approval of its DER application, the Company plans to issue an RFP to solicit solar PPA and engineering, procurement and construction ("EPC") turnkey proposals in order to procure or build the first tranche of Shared Solar program capacity, equal to approximately 4,000 kW, in DEP's retail service area in South Carolina. Bidders will be asked to submit proposals for projects no greater than 1,000 kW with a target in service date prior to December 31, 2016.

Q. PLEASE DESCRIBE THE COMPANY'S PLAN TO PROCURE RENEWABLE ENERGY FROM LARGE-SCALE SOLAR FARMS.

A. In addition to the RFP for resources less than 1,000 kW described previously in my testimony, and within 90 days of Commission approval of its DER application, the Company will solicit 40 MW of solar photovoltaic capacity through an RFP for facilities located in its service territory in South Carolina. The Company will require that facilities are in-service before the end of 2016, such that pricing will reflect the benefits of the federal investment tax credit, which is set to expire Dec. 31, 2016. The Company anticipates that several such arrays will be built across its retail service area, thus delivering economic development benefits to communities within its service territory. Company witness Jose I. Merino testimony includes additional details regarding this proposed procurement activity.

Q. DO YOU BELIEVE THIS APPLICATION MEETS THE REQUIREMENTS OF ACT 236 AND THE SETTLEMENT AGREEMENT?

A. Yes, I believe this application meets the requirements that the General Assembly set forth in Act 236, as well as the terms of the Settlement Agreement reached in Docket 2014-246-E. Fulfillment of the goals of Act 236 and the terms of the Settlement Agreement was a primary design principle around which this portfolio of initiatives was crafted. To illustrate the congruence between the Company's estimated DER generation targets, as set forth in S.C. Code § 58-39-130, and the Company's proposed DER initiatives, please refer to Figure 1, which is an estimation of the DER capacity the Company expects in each the programmatic areas over the next few years. Please note that in 2020, the Company expects an estimated 84,000 kW, or 84 MW, of DER capacity to be operational. It is also very important to note that this figure is a projection for planning purposes only and many factors, including but not limited to changes in subsidies for solar energy systems and technology cost decline, will drive customer adoption of the proposed solar programs.



Q. ACT 236 REQUIRES THAT TWENTY-FIVE PERCENT (25%) OF ONE PERCENT OF THE COMPANY'S RETAIL SOUTH CAROLINA FIVE YEAR AVERAGE PEAK DEMAND MUST BE FROM FACILITIES LESS THAN 20 KW IN NAMEPLATE CAPACITY. HOW DOES THE COMPANY PROPOSE TO MEET THAT REQUIREMENT?

A. The capacity requirement relating to smaller-scale generation, the "0.25% requirement," set forth in S.C. Code 58-39-130(C)(2), is the most difficult to achieve, given the relatively high cost of entry presented by rooftop solar photovoltaic generation, and the fact that a very small fraction of the Company's South Carolina retail customers have the income, wealth, credit score, home, and roof to support a solar investment on-site. In order to meet this goal, and in order to provide access to the benefits of solar energy systems to a diversity of customers, the Company proposes that capacity from Shared Solar farm subscribers (if the share is less than 20 kW) as well as participants in the Solar Rebate Program (if the capacity is less than 20 kW) qualify toward meeting this goal.

Q. DO YOU BELIEVE THE COMPANY'S PORTFOLIO OF DER PROGRAMS WILL PROVIDE A REASONABLE OPPORTUNITY TO ACHIEVE THE CAPACITY REQUIREMENTS OF ACT 236?

A. Yes, as also detailed in the testimony of Company witness Merino, the Company has conducted significant economic analysis and forecasting to both establish the level of the incentives within these programs, and project the customer adoption response to these offers. We believe these programs and incentives offer meaningful benefits to customers choosing to install DER generation and will drive adoption to meet the capacity requirements of the Act.

Q. HOW AND WHEN WILL THE COMPANY ACTUALLY IMPLEMENT THE PROGRAMS?

A. The Company is prepared to take swift action upon Commission approval of its DER Application. The Company proposes to release an RFP for solar facilities located in its service territory in South Carolina within ninety (90) days of DER program approval and plans to reach the large-scale capacity goal of approximately 40 MW by the end of 2016. With respect to its solar programs to incent the development of smaller facilities either owned or leased by customers, the Company plans make available to customers the Solar Rebate Program and the Shared Solar Program within 3 months and 12 months of DER program approval, respectively. The latter requires the Company to secure Shared Solar facilities, most likely 1,000 kW, ground-mount solar generation facilities, prior to offering subscriptions to the customer. With regard to the DER NEM Incentive, it will automatically become available to customers taking service under the Company's NEM tariff.

Q. WHY HAS DEC PROPOSED TO MAKE DER INCENTIVES AVAILABLE RETROACTIVELY?

A. The Company has proposed to make the DER Incentives described above available to customers retroactively in order to enable the nascent South Carolina solar development industry, in particular, the ability to continue to do business during the period during which the Commission is considering the Companies' DER application. Providing that level of certainty at the outset will hopefully provide more detailed information and assurances to developers and customers as they consider possible solar investment in the Company's service territory.

Q. THE APPLICATION STATES THAT THE COMPANY SEEKS THE ABILITY TO CHANGE TARIFFS AND INTRODUCE NEW PROGRAMS IN THE FUTURE. WHY IS THAT NECESSARY?

A. The Company believes that we must be mindful that the relative value of the offered incentives will change over time, particularly as these resources develop in South Carolina. As such, we feel that any program should be adaptable over time to reflect any changes to market conditions. The ability to update and revise programs after implementation is underway will also give DEC the opportunity to ensure that its customers are paying no more than they should to incent the development of DER under the Act. The DER market is a very dynamic one at this time and DEC is simply seeking to retain the ability to be agile and adaptable to such dynamic conditions as the market develops and evolves in the State.

III. CONCLUSION

Q. DO YOU BELIEVE THE COMPANY'S PORTFOLIO OF PROGRAMS ARE REASONABLE AND IN THE PUBLIC INTEREST?

A. Yes, I do. The Company is committed to fully supporting the comprehensive and holistic goals of Act 236 and the terms of the Settlement Agreement and we have carefully designed our initiatives to achieve those goals.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

DOCKET NO. 2015-55-E

	)	
In the Matter of:	)	
	)	
Application of	)	**DIRECT TESTIMONY OF JOSE**
Duke Energy Carolinas, LLC to	)	**I. MERINO ON BEHALF OF**
Establish a Distributed Energy	)	**DUKE ENERGY CAROLINAS,**
Resource Program	)	**LLC**
	)	

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jose I. Merino. My business address is 400 South Tryon, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION WITH THE COMPANY?

A. I currently serve as Director of Renewable Analytics for Duke Energy Corporation (“Duke Energy”).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I received a Bachelor of Arts degree in Finance and Economics from Florida State University in August 1995. In May 2001, I received a Master of Science degree in Management from Georgia Institute of Technology with a specialization in Marketing and Finance. In December 2010, I graduated from the University of North Carolina at Charlotte with a Master of Arts degree in Economics. I joined Duke Energy Corporation (“Duke Energy”) in July 2001 as a Commercial Associate in the Corporate Strategy Department. After completing two years of rotational assignments in Charlotte, Houston and Salt Lake City, I joined the Corporate Risk organization as a Corporate Credit Manager. In 2004, I accepted a position in Duke Power Company, a subsidiary of Duke Energy, as Planning and Compliance Manager for the Bulk Power Marketing area. The main responsibilities for this role included revenue and cost projections and compliance with mandates of different regulatory bodies regarding regulated trading operations. After Duke Energy merged with Cinergy in 2006, I moved to the Market Analytics group to supervise a team that provided planning, marketing and analytical support to the company's Economic and Business Development organizations. In 2008, I became Director, Wholesale and Commodities Business Support. This function, which I supervised, was primarily accountable for projecting fuel consumption for Duke Energy's regulated generation fleet, forecasting revenues and costs for Duke Energy's regulated portfolio optimization groups, and providing analytical support to wholesale origination. In October 2010, I accepted a position in charge of load forecasting. As a result of the merger with Progress Energy, Inc. in July 2012, my responsibilities were expanded to supervise both the load and fundamental forecasting teams for the combined company. I started my current job as Director of Renewable Analytics in July 2014.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AS DIRECTOR OF RENEWABLE ANALYTICS?

A. As Director of Renewable Analytics, I am responsible for managing the personnel, processes and systems required to provide reporting, financial analysis, research and project management support to Duke Energy's regulated Distributed Energy Resources department.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support Duke Energy Carolinas, LLC's ("DEC" or "the Company") financial analysis and modeling assumptions relating to its projected achievement of the capacity targets within Act 236 through its proposed Distributed Energy Resource ("DER") Program. My testimony also specifically addresses the Company's customer adoption assumptions arising from its Solar Rebate and Shared

Solar Programs, as well as the incentive levels included within those respective programs.

Q. DO YOU HAVE ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. Merino Exhibit 1 illustrates the Company's derivation analysis supporting its proposed Solar Rebate and Merino Exhibit 2 provides the subsidy, subscription charge and projected bill savings derivation analysis related to its proposed Shared Solar program.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes.

II. <u>OVERVIEW OF ACT 236 REQUIREMENTS</u>

Q. WHAT ARE THE MINIMUM ACHIEVEMENT TARGETS FOR UTILITIES PROPOSING TO PARTICIPATE IN A DER PROGRAM UNDER ACT 236?

A. For utilities choosing to propose and participate in a DER Program pursuant to Act 236, it specifically requires the utility to (1) invest in or procure one percent (1%) of South Carolina retail peak capacity from large scale renewable energy facilities, no less than 1,000 kilowatts ("kW") and no greater than 10,000 kW in nameplate capacity (referred to as "Tier I"), and (2) establish programs to encourage customers to purchase or lease renewable energy facilities (no greater than 1,000 kW in capacity) that, in aggregate, are equivalent in nameplate capacity to one percent (1%) of South Carolina retail peak capacity, of which twenty-five percent (25%) must be from facilities less than 20 kW in nameplate capacity (referred to "Tier II").

Q. HAS THE COMPANY'S DER PROGRAM BEEN SPECIFICALLY DESIGNED TO ACHIEVE THESE CAPACITY TARGETS?

A. Yes, the Company's proposed DER portfolio was designed to meet the nameplate capacity goals associated with large scale renewable facilities up to 10,000 kW and to promote the necessary investment in small scale renewable facilities that can serve residential, commercial and industrial customers and meet the aggregate nameplate capacity requirements for facilities less than 1,000 kW.

Q. HOW MUCH DER CAPACITY IS THE COMPANY PLANNING TO BRING ONLINE THROUGH THE IMPLEMENTATION OF ITS PROGRAMS IN EACH OF THE COMPONENT SEGMENTS?

A. The Company projects to bring online a total of 84 megawatts ("MW") of installed capacity between 2015 and 2020 through the implementation of Tier I and Tier II programs. The projected breakdown of total DER capacity by Tier is as follows: for Tier I, 40 MW; and for Tier II, 44 MW.

III. RENEWABLE ENERGY REQUEST FOR PROPOSALS ("RFP")

Q. PLEASE DESCRIBE THE PLANNED RFP FOR RENEWABLE ENERGY RESOURCES TO SOLICIT PROPOSALS TO MEET THE TIER I REQUIREMENTS OF ACT 236.

A. Within 90 days of Commission approval of its DER application, **t**he Company plans to issue an RFP to solicit utility scale solar photovoltaic purchased power agreements ("PPA") and utility scale solar engineering, procurement and construction ("EPC") turnkey projects in order to procure or build approximately 53 MW (AC) of installed capacity in South Carolina (to meet the Tier I requirements for both the Company and Duke Energy Progress, Inc. ("DEP")). Bidders will be asked to submit proposals for projects greater than 1 MW and equal or less than 10 MW (AC) with a target in service date prior to December 31, 2016. The desired contract period will be 10 years or less and the price will be dictated by the RFP selection process. The proposals will be evaluated based on a set of attributes as prescribed by the Company's competitive bidding process.

Q. BASED ON YOUR ANALYSIS OF THE MARKETPLACE, DOES THE COMPANY EXPECT TO RECEIVE COST COMPETITIVE PROPOSALS TO MEET THE ENTIRE REQUIREMENT?

A. The Company hopes to obtain meaningful market and competitive pricing information from the RFP responses it expects to receive. There is minimal market activity in South Carolina related to utility scale solar projects at this time. By establishing a competitive bidding process, the Company believes all market participants will gain new insight about relative cost competitiveness of renewable resources in the State.

Q. WILL COST BE THE PRINCIPAL FACTOR IN THE SELECTION OF PROJECTS THROUGH THE RFP?

A. Yes. Cost will be the main component in the RFP selection process but the Company will also evaluate other important attributes such as deliverability, reliability, safety, the commercial viability of the technology selected, credit and other risks.

Q. DO YOUR ASSUMPTIONS INCLUDE OTHER TIMING AND LOGISTICAL REQUIREMENTS FOR SELECTING PROJECTS THROUGH THE RFP?

A. Yes. The Company intends to conduct the RFP so that the selected projects have ample time to plan, design, obtain permits and build the necessary interconnection infrastructure in order deliver energy to the grid by December 31, 2016 and qualify for the applicable federal and state tax credits.

Q. FROM AN ANALYTICAL PERSPECTIVE, DO YOU BELIEVE THE PROPOSED RFP IS A REASONABLE AND APPROPRIATE MEASURE TO ACHIEVE THE TIER I CAPACITY REQUIREMENT?

A. Yes. DEC believes that relying on a RFP for utility scale solar facilities is a cost-effective approach to comply with its Tier I capacity requirements, promote the benefits of the proposed DER portfolio and increase awareness about the new DER market structure in South Carolina. Based on the Company's past experience with issuing RFPs for conventional and renewable generation, awarding contracts and executing projects, we expect to achieve the desired penetration levels while keeping costs at a reasonable level.

IV. CUSTOMER INCENTIVE PROGRAMS

a. *DER Net Energy Metering ("NEM") Incentive*

Q. PLEASE DESCRIBE THE COMPANY'S DER NEM INCENTIVE.

A. The DER NEM incentive will be available to existing and new NEM customers who take service under the Company's new NEM tariffs prior to December 31, 2020. The DER NEM incentive will expire at the end of 2025 and will be fully funded by the Company's DER program through the end of 2025. Customers that select NEM service after December 31, 2020 will not be eligible to receive the DER NEM incentive.

The DER NEM incentive is calculated, pursuant to the methodology set forth within the Settlement Agreement approved by the Public Service Commission of South Carolina ("Commission") in Docket No. 2014-246-E ("NEM Settlement Agreement"), and described more fully in the testimony and Attachment A of DEC and DEP witness Jeffrey R. Bailey in that proceeding. In sum, as calculated under the methodology set forth in the NEM Settlement Agreement, the DER NEM incentive represents the difference between the revenue requirement of the customers within a rate class and the specific net value of the generation delivered by an NEM customer-generator within that class, taking into account estimated amounts paid by the customer-generator through their monthly bill. In this way, the DER NEM Incentive represents the additional embedded incentive that must be provided to an NEM customer-generator for that customer-generator to receive a full 1:1 retail rate credit.

Q. DO THE COMPANY'S ADOPTION ASSUMPTIONS RELY UPON NEM CUSTOMERS CONTINUING TO RECEIVE THE DER NEM INCENTIVE FOR THE DURATION OF ITS DER PROGRAM?

A. Yes. The Company's projections take into account the impact of the embedded DER NEM incentive and are adjusted accordingly when the incentive expires at the end of 2025.

Q. FOR PURPOSES OF ITS DER PROGRAM APPLICATION, HAS THE COMPANY CALCULATED ITS DER NEM INCENTIVE IN A MANNER CONSISTENT WITH THE REQUIREMENTS OF THE SETTLEMENT AGREEMENT IN DOCKET NO. 2014-246-E ("NEM SETTLEMENT AGREEMENT")?

A. Yes. However, it is important to note that at this time, the Company does not yet have an approved per-kilowatt-hour ("kWh") value for NEM resources. It is my understanding that such approval will occur with the approval of the Company's new NEM tariff, which must be filed within 60 days of the issuance of the Commission's Order in Docket No. 2014-246-E. As such, for purposes of the Company's initial DER application, it has used its current avoided cost values as a proxy for the value of NEM generation, and derived its projected DER NEM incentive accordingly, using the benefit-cost methodology included within the NEM Settlement Agreement. In future proceedings, DEC will use the approved per-kWh value of NEM generation to support the level of the DER NEM incentive calculated through the methodology approved in Docket No. 2014-246-E.

Q. WITHOUT THIS INCENTIVE, WOULD THE COMPANY'S ADOPTION ASSUMPTIONS BE THE SAME?

A. No. Without the DER NEM incentive, the projected adoption for net metering installation would be lower between 2015 and 2025. Based on our models and recent NEM penetration trends in South Carolina, the probability of reaching the Tier II goals without a DER NEM incentive is very low.

Q. AS SUCH, DOES THE COMPANY BELIEVE THE DER NEM INCENTIVE WILL BE AN IMPORTANT DRIVER IN ACHIEVING ITS TIER II CAPACITY REQUIREMENTS?

A. Yes. The forecasted NEM growth is an important contributor to achieving the MW installed capacity goals for Tier II in DEC's service territory.

Q. BASED ON YOUR ANALYSIS, WOULD THE DER NEM INCENTIVE, BY ITSELF, BE ENOUGH TO DRIVE CUSTOMER ADOPTION SUFFICIENT TO MEET THE TIER II CAPACITY REQUIREMENT?

A. No. Based on the Company's analysis, the DER NEM incentive by itself would be insufficient to provide the necessary economic return to drive customer adoption. Under the Company's current NEM tariffs, which also incorporate a full 1:1 retail rate credit for NEM generation, DEC only has 165 NEM customers. Such tariffs have been in place since 2008, and the Company has simply not experienced any meaningful customer adoption to date.

It bears noting that, from a customer perspective, it is less expensive to purchase energy from the Company at the existing retail rate than it is to invest in a solar facility and enter into an NEM agreement. At this time, the expenses associated with purchasing and installing a solar array, conducting periodic maintenance and paying for insurance and property taxes, are higher than the bill savings caused by the solar production and the resulting lower customer energy consumption. The Company's renewable analytics team estimates that the levelized cost of energy ("LCOE"), over a 25 year period, priced at the existing retail rates, is lower than the LCOE associated with investing in a rooftop photovoltaic solar facility and paying a bill, under the applicable rate schedule and NEM tariff. The upfront costs of a solar facility and the projected declining energy production profile driven by panel degradation are the main reasons why it does not represent an better alternative than the Company's electric rate under present conditions. Table 1 below illustrates the comparison of LCOEs between the two alternatives for a typical residential customer.

TABLE 1

25 YEAR LEVELIZED COST OF ENERGY FOR A SC RESIDENTIAL CUSTOMER($/KWH)

	2015
a) Regular Residential Bill	$ 0.13
b) Regular Residential Bill + Solar Investment + NEM Rider	$ 0.15
c) Regular Residential Bill + Solar Investment + NEM Rider + Solar Rebate	$ 0.14

The calculation depicted in Table 1 reflects the estimated levelized all-in energy expense over the next 25 years for a typical South Carolina residential customer. The analysis includes all cash flows that are reasonably expected to take place between 2015 and 2040, including all items in the retail rate schedule, the cost of the solar facility, tax benefits, operational and maintenance expenses, and the expiration of the NEM DER incentive in 2025.

Q. SO IN YOUR OPINION, ADDITIONAL INCENTIVE BEYOND THE DER NEM INCENTIVE WILL BE REQUIRED TO DRIVE THE ADOPTION NECESSARY TO MEET THE TIER II REQUIREMENT?

A. Yes. From my perspective, it is necessary to provide incentives beyond the 1:1 retail rate until DER technology costs, existing retail rates, reliability and other market drivers reach a point where customers are indifferent between choosing DER over conventional energy supply.

Q. AND THE OTHER PROGRAMS WITHIN THE PROPOSED DER PROGRAM PORTFOLIO, SPECIFICALLY THE SOLAR REBATE AND SHARED SOLAR PROGRAMS, ARE INTENDED TO DRIVE THAT ADDITIONAL ADOPTION?

A. Yes, they are intended to do so.

b. *Solar Rebate Program*

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSED SOLAR REBATE PROGRAM.

A. The Company's solar rebate program is a new tariff that was designed to promote investment growth in DER technologies, particularly for small scale residential and commercial renewable generation facilities. The form of the rebate is an upfront cash payment, based on a stated dollar per watt DC of installed nameplate capacity. The solar rebate will be available to residential and non-residential customers who desire to purchase or lease a DER on their property. The goal of the rebate is to reduce out-of-pocket expenses for customers and/or leasing companies. Residential customers will receive a one-time $1.00 per watt rebate from the utility once all of the tariff conditions are met, as delineated in Exhibit A of the Company's DER Application. Similarly, a qualifying non-residential customer will receive $0.70 per watt after all the tariff requirements are satisfied. The contract period for the solar rebate is 5 years and customers have an option of early termination, subject to payment of reasonable termination charges.

Q. HOW DID THE COMPANY ARRIVE AT THE PROPOSED INCENTIVE LEVELS WITHIN THE PROPOSED SOLAR REBATE PROGRAM?

A. The rebates were determined after performing a comprehensive analysis of the expected economic impact to South Carolina residential and non-residential customers, the effects on the DER cost caps per customer class, the implications for 3rd party developers and the overall growth of the distributed energy resources industry. The rebates were established to provide a clear and tangible boost to the DER market such that DEC achieves its stated penetration goals in a cost effective, reliable and safe manner. The Company tested the rebate level against the effects of state and federal tax credits, taking into consideration the incremental cost caps and cost allocation to which the programs must conform, and evaluated it under the guiding standard of overall reasonableness and simplicity. The Company's confidential rebate derivation analysis is set forth in Merino Exhibit 1, provided with my testimony.

Merino Exhibit 1 illustrates an example of the main inputs and outputs from a residential model, which were used to assess the effectiveness of the Solar Rebate. The cells highlighted in yellow depict the percentage of the solar capital expenditure that is covered by the Solar Rebate, and the line chart compares the customer's annual cash position under different solar cost scenarios and availability of rebates.

Q. WHY DID THE COMPANY CHOOSE TO PROVIDE REBATES ONLY TO SOLAR INSTALLATIONS?

A. Initially, the Company considered programs and tariffs for not only solar photovoltaic ("PV") but also solar thermal, combined heat and power, wind, electric vehicle charging, and small scale biomass. However, given that Act 236 requires programs to encourage customers of the electrical utility to purchase or lease renewable energy facilities, given that solar PV is by far the most accessible and scalable customer generation type, the Company chose to focus its efforts on solar PV at this time.

Q. HAS THE COMPANY BENCHMARKED THE PROPOSED SOLAR REBATE TO DELIVER A SPECIFIC RETURN ON INVESTMENT FOR CUSTOMERS ADOPTING SOLAR THROUGH THE PROGRAM?

A. No. The solar rebate was not benchmarked to deliver a specific return on investment for customers. In its analysis for the Solar Rebate, the Company considered and studied commonly-used metrics for measuring financial return, such as internal rate of return, simple payback period or net present value. These metrics informed the Company's review, but were not the main driver of the ultimate solar rebate amounts. Instead, the solar rebate was developed to approximate a pre-defined percentage of the total expected upfront investment required to install a small scale PV solar facility. We believe that an upfront rebate will complement existing federal and state tax credits well, since those benefits can also be realized shortly after a solar installation is operational. Based on our internal assessment as well as a 2012 report published by the National Renewable Energy Laboratory ("NREL")[1], we estimated that if the solar rebate represents between 20% and 25% of the projected installed costs of a residential or commercial solar photovoltaic rooftop, customer adoption will increase because the balance of the capital expenditure outlay can be offset, in part, by existing tax incentives.

Q. BASED ON YOUR ANALYSIS, ARE THE PROPOSED SOLAR REBATE LEVELS NO HIGHER THAN THEY NEED TO BE TO DRIVE CUSTOMER ADOPTION TO ACHIEVE THE STATUTORY TIER II REQUIREMENTS?

A. Yes. The Company estimated and derived the solar rebate using the best available information for solar rooftop costs, current tax credits, economic conditions and customer preferences in its service area. As those variables change over time, the economics from the customer perspective will change. These changes in economic conditions will likely cause the amount of the rebate to fluctuate. As such, our analysis shows that the rebates needed to offset a portion of the installed costs will vary over time.

Q. FROM AN ANALYTICAL PERSPECTIVE, ARE THE PROPOSED SOLAR REBATE LEVELS SUFFICIENT TO DRIVE CUSTOMER ADOPTION OF OWNED OR LEASED SYSTEMS TO HELP TO MEET THE TIER II REQUIREMENTS?

A. Yes. DEC believes that the proposed rebate amounts for residential and non-residential customers will be sufficient to achieve the installed capacity targets set forth in Act 236.

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[1] Lori Bird, Andrew Reger, and Jenny Heeter. 2012. "Distributed Solar Incentive Programs: Recent Experience and Best Practices for Design and Implementation." National Renewable Energy Laboratory

Q. HOW DOES THE COMPANY PROJECT THAT CUSTOMERS WILL ADOPT UNDER THE SOLAR REBATE PROGRAM?

A. The Company analyzed historical solar penetration trends in states where the market is more mature or incentives were implemented. More specifically, the Company looked at data for California and Arizona electric utilities. The historical penetration in those states and other parameters, such as current South Carolina rates, solar pricing, tax rates and economic conditions, were reviewed by the business development and analytics teams to produce a forecast for solar penetration in DEC and DEP. The Company believes that between 2015 and 2017, customers will adopt DER because the cost of investing in a solar array will be materially reduced due to available tax credits and the Company's Solar Rebate. After 2017, the Company projects that penetration will continue to increase, albeit at a slower pace, in spite of the ramp down of the Federal ITC from 30% to 10%, because solar installation costs are trending downward.

Q. IN THE EVENT THAT CUSTOMER ADOPTION EITHER EXCEEDS OR FAILS TO MEET THE COMPANY'S FORECASTS FOR ADOPTION, WILL IT PROPOSE ADJUSTMENTS TO THE SOLAR REBATE OVER TIME?

A. Yes. As I stated previously, as economic conditions in our service territory change over time, the solar rebate should also change accordingly. Subject to the potential impact on the Company's cost projections and other alternatives that may arise as the DER market matures, the Company's plan is to periodically evaluate the level and effectiveness of the solar rebate program based on past performance and market research.

c. *Shared Solar Program*

Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED SHARED SOLAR PROGRAM.

A. The Shared Solar program is a subscription-based DER offer that is designed principally for customers that do not have adequate rooftops, that hold a tax-exempt status, that live in multi-family housing where it may be difficult to obtain the proper permits to install solar, that rent or lease their home or customers who do not have the capital or credit score to afford to purchase or lease a solar array. By paying a monthly subscription and small up-front charges, multiple participants can subscribe to a pro-rata share of the energy produced by a ground-mount solar facility for a period of ten (10) years. Shared Solar customers will receive a monthly energy credit based on the actual kWh generated by their Solar subscription and the energy credit will be based on the value of DER methodology prescribed in the NEM Settlement Agreement. In addition, subscribers will pay the Company for all energy consumed at the prevailing retail rate. The energy consumed will not be netted against the energy produced by their Shared Solar subscription for billing purposes or for any other reason. The Shared Solar program was designed so that participants realize bill savings relative to what their bills would have been if they did not subscribe to the program. The customer savings are possible because the Shared Solar subscription fee includes an embedded subsidy; without such incentive, the required subscription fee would have been higher in order to cover the costs of the program.

Q. HOW AND WHEN WILL THE COMPANY SECURE THE SHARED SOLAR PROGRAM RESOURCES?

A. As described by Company witness Felt, within 90 days of Commission approval of its DER application, the Company plans to issue an RFP to solicit solar PPA and EPC turnkey proposals in order to procure or build the first tranche of Shared Solar program capacity, equal to approximately 1,000 kW, in DEP's retail service area in South Carolina. Bidders will be asked to submit proposals for projects no greater than 1,000 kW, with a target in-service date prior to December 31, 2016. This procurement will be bundled with the RFP for resources to meet the Tier I requirements of Act 236, described earlier in my testimony.

Q. MORE SPECIFICALLY, PLEASE ELABORATE ON THE INCENTIVE STRUCTURE WITHIN THE PROPOSED SHARED SOLAR PROGRAM.

A. The Shared Solar customer charges and credits were designed such that participating customers experience a bill savings of approximately $25 per kW DC subscribed during the first few years of operation of the solar facility; these saving are expected to provide the customer with a simple payback period of four (4) years. The embedded utility subsidy is calculated by taking the difference between the projected costs to procure or produce energy from the Shared Solar facilities and the established monthly subscription charge. The Company's confidential Shared Solar subsidy, subscription charge and projected bill savings derivation analysis is set forth in Merino Exhibit 2, provided with my testimony.

It is important to note that in the absence of a subsidy, participating customers would pay the full cost of their share of the Shared Solar facility, which would result in a higher energy bill as compared to simply obtaining electric service under the applicable retail rate schedule. As set forth in Merino Exhibit No. 2, the embedded utility subsidy is the difference between the projected costs to procure the Shared Solar facilities and the established monthly subscription charge.

Q. HAS THE COMPANY BENCHMARKED THE PROPOSED LEVEL OF INCENTIVE IN THE SHARED SOLAR PROGRAM TO DELIVER A SPECIFIC AMOUNT OF BILL SAVINGS FOR CUSTOMERS ADOPTING SOLAR THROUGH THE PROGRAM?

A. Yes. The proposed level of incentives included in the Shared Solar offer were developed to produce approximately 8% bill savings in year one for a typical residential and non-residential customer. Depending on the respective customers' load profile, the retail rate schedule that such customer is paying and the production profile of the Shared Solar facility, the actual bill savings in year one may be different than the target level.

Q. DOES THE COMPANY BELIEVE THE EMBEDDED SUBSIDY AND BILL SAVINGS INCENTIVES ARE REASONABLE AND APPROPRIATE MEANS TO DRIVE ADOPTION TO MEET THE TIER II REQUIREMENTS?

A. Yes. The Company believes that the expected bill savings and short payback period will be sufficient to entice customers within the Shared Solar target segments to subscribe to the program. In the Company's opinion, the customer segments that represent an ideal market for this program are tax-exempt entities and customers who may not have an adequate roof in terms of angle, area or overall sun exposure.

Q. GIVEN THE TARGETED CUSTOMER SEGMENT, IS IT THE COMPANY'S INTENTION TO ALSO USE THIS PROGRAM TO MEET THE

REQUIREMENTS OF S.C. CODE § 58-39-130(C)(3) RELATING TO PROGRAMS FOR TAX-EXEMPT AND GOVERNMENTAL ENTITIES?

A. Yes, that is a parallel goal of the Shared Solar program.

Q. TAKING THE NEED FOR THESE INCENTIVES INTO ACCOUNT, ARE THE PROPOSED INCENTIVE LEVELS IN THE SHARED SOLAR PROGRAM NO HIGHER THAN THEY NEED TO BE TO DRIVE CUSTOMER ADOPTION TO ACHIEVE THE STATUTORY TIER II REQUIREMENTS?

A. Yes. The Company believes that the current level of Shared Solar incentives is commensurate with the assistance needed to drive adoption by the average South Carolina residential and non-residential customer, given current DER technology costs, tax credits and economic conditions in the Company's service territories.

Q. FROM AN ANALYTICAL PERSPECTIVE, ARE THE INCENTIVE LEVELS IN THE PROPOSED SHARED SOLAR PROGRAM SUFFICIENT TO DRIVE CUSTOMER ADOPTION OF SHARED SOLAR TO HELP TO MEET THE TIER II REQUIREMENTS?

A. Yes. We believe that the proposed Shared Solar incentives are adequate to drive the required penetration of Shared Solar needed to meet the Company's Tier II DER installed capacity requirements.

Q. IN THE EVENT THAT CUSTOMER ADOPTION EITHER EXCEEDS OR FAILS TO MEET THE COMPANY'S FORECASTS FOR ADOPTION, WILL IT PROPOSE ADJUSTMENTS TO THE SHARED SOLAR PROGRAM OVER TIME?

A. Yes. Like the solar rebate program, as economic conditions change within the Company's service territory, the incentive required to drive customer adoption of the Shared Solar program will likely also change. As such, subject to the potential impact on the Company's cost projections and other alternatives that may arise as the DER market matures, the Company's plan is to periodically evaluate the level and effectiveness of the Shared Solar program based on past performance and market research, and make adjustments as necessary.

V. CONCLUSION

Q. DOES THE COMPANY'S PORTFOLIO OF DER PROGRAMS PROVIDE IT WITH A ROBUST OPPORTUNITY TO ACHIEVE THE CAPACITY REQUIREMENTS OF ACT 236?

A. Yes. The proposed DER portfolio was developed to provide a diverse set of programs to serve the needs of third party providers, leasing companies, residential and non-residential customers in a reliable, safe and cost-effective manner.

Q. BASED ON YOUR ANALYSIS AND RESEARCH, IS THE COMPANY'S PORTFOLIO OF PROPOSED DER PROGRAMS, IN TOTALITY, REASONABLE AND APPROPRIATE TO DRIVE CUSTOMER ADOPTION OF RENEWABLE ENERGY RESOURCES IN SOUTH CAROLINA?

A. Yes. Collectively, the utility scale RFP and proposed customer offers included the Company's proposed DER portfolio include tangible and meaningful incentives that will drive the necessary customer adoption and achieve the targets stipulated in Act 236. The programs included in the DER portfolio were designed to be cost-effective and easy to implement, administer and monitor. Ultimately, customer response will dictate the achievement of the Tier I and II capacity requirements, but this portfolio provides strong customer offers designed to incent the required adoption by 2021.

Q. ARE THE COMPANY'S ASSUMPTIONS OF CUSTOMER ADOPTION THROUGH THE PROPOSED PORTFOLIO OF PROGRAMS REASONABLE AND SUPPORTED BY THE DATA AVAILABLE TO THE COMPANY AT THIS TIME?

A. Yes. The assumptions identified to support the analysis of the proposed DER portfolio were validated through a rigorous review process, are aligned with other internal company inputs and come from industry-accepted sources and the Company's own market information. For example, the projected costs for solar photovoltaic generation were derived by analyzing the available forecasts from three industry-accepted firms, by consulting with local installers and from internal company records. Further, the Company's assumptions associated with tax benefits or costs were reviewed with the Company's tax department and the assumptions for DER penetration projections were checked against recent trends in comparable jurisdictions and by examining the existing penetration in response to comparable customer offers in other jurisdictions.

Q. FINALLY, ARE THE INCENTIVE LEVELS DRIVING THOSE ASSUMPTIONS REASONABLE UNDER CURRENT MARKET CONDITIONS, SUCH THAT THE COSTS OF SUCH INCENTIVES ARE NO HIGHER THAN THEY SHOULD BE AT THIS TIME?

A. Yes. The Company's analytics and business development teams developed multiple scenarios to assess the potential impact of different customer offers and incentive structures on the DER portfolio costs and penetration levels. Based on the results of this analysis, the selected incentives should provide the right amount of stimulus to the industry, considering available tax credits, current DER installed costs and electricity prices.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE

THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2015-55-E

In Re:	)
	)
Duke Energy Carolinas, LLC	)
To Establish a Distributed Energy	)
Resource Program	)
	)

JOSE I. MERINO
CONFIDENTIAL EXHIBIT 1

FILED UNDER SEAL

MARCH 17, 2015

SOLAR REBATE DERIVATION ANALYSIS

[redacted]

BEFORE

THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2015-55-E

In Re:	)
	)
Duke Energy Carolinas, LLC	)
To Establish a Distributed Energy	)
Resource Program	)
	)

JOSE I. MERINO
CONFIDENTIAL EXHIBIT 2

FILED UNDER SEAL

MARCH 17, 2015

SHARED SOLAR SUBSIDY DERIVATION ANALYSIS

[redacted]

BEFORE THE
PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA
DOCKET NO. 2015-55-E

In the Matter of	)	
	)	
Application of	)	**DIRECT TESTIMONY**
Duke Energy Carolinas, LLC to	)	**OF KIM H. SMITH**
Establish a Distributed Energy	)	**ON BEHALF OF**
Resource Program	)	**DUKE ENERGY CAROLINAS, LLC**
	)	
	)	

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kim H. Smith. My business address is 550 South Tryon Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Rates Manager for Duke Energy Carolinas LLC ("Duke Energy Carolinas," "DEC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Marshall University with a Bachelor of Business Administration degree, and received a Master of Business Administration degree from the University of Charleston. I am a certified public accountant licensed in the state of North Carolina. I began my career with DEC in 2006 as an external reporting manager. Since I joined the Rate Department in 2008 as Rates Manager I have been responsible for providing regulatory support for retail and wholesale rates, providing guidance on DEC's and Duke Energy Progress, Inc.'s ("DEP") (collectively, the "Utilities") Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") compliance and cost recovery applications, energy efficiency cost recovery, and fuel and fuel-related recovery processes.

Q. PLEASE DESCRIBE YOUR DUTIES AS RATES MANAGER FOR DEC.

A. I am responsible for providing regulatory support for retail and wholesale rates, and providing guidance on DEC's fuel and fuel-related cost recovery application in North Carolina, and its fuel and environmental cost recovery application in South Carolina.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA?

A. Yes. I testified before the Public Service Commission of South Carolina ("PSCSC" or "Commission") in DEC's 2014 and 2013 fuel and environmental cost recovery proceedings in Docket Nos. 2014-3-E and 2013-3-E.

Q. ARE YOU FAMILIAR WITH THE ACCOUNTING PROCEDURES AND BOOKS OF ACCOUNT OF DEC?

A. Yes. Duke Energy Carolinas' books of account follow the uniform classification of accounts prescribed by the Federal Energy Regulatory Commission ("FERC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide DEC's actual distributed energy resource ("DER") incremental and avoided cost data for June 1, 2014 through May 31, 2015 (the "review period"), the projected DER incremental and avoided cost information for June 1, 2015 through September 30, 2015 (the "forecast period"), and DEC's proposed DER incremental and avoided cost factors by customer class for October 1, 2015 through September 30, 2016 (the "billing period"). In addition, my testimony describes and supports the parameters used for allocating costs and establishing billing factors for customer classes.

Q. PLEASE DESCRIBE THE PARTICULAR COSTS THE COMPANY HAS INCLUDED IN ITS DER APPLICATION.

A. According to S.C. Code § 59-39-130 (A)(2), an electrical utility shall be permitted to recover its costs related to approved DER programs pursuant to S.C. Code §§ 58-27-865 and 58-39-140, to the extent those costs are reasonably and prudently occurred to implement an approved program. In this proceeding, the Company is seeking approval of its DER programs and its proposed method of allocating and recovering the incremental and avoided costs of such programs. DEP will seek actual recovery of those costs in its annual fuel proceeding.

Q. WHAT IS AN INCREMENTAL COST IN GENERAL?

A. According to S.C. Code § 58-39-140, "incremental costs" means all reasonable and prudent costs incurred by an electrical utility to implement a distributed energy resource program. Incremental costs include but are not limited to:

- The cost an electric utility incurs in excess of the electrical utility's avoided cost rate;
- The full cost of an electrical utility's investment in non-generating distributed energy resources, such as, but not limited to, energy storage devices;
- The electrical utility's weighted average cost of capital as applied to the electrical utility's investment in distributed energy resources;
- Expenses associated with a project, asset or program under generally accepted principles of regulatory or utility accounting or accounting orders issued by the commission; and
- The electrical utility's incremental labor cost associated with implementing a distributed energy program.

Q. WHAT IS AN AVOIDED COST?

A. Avoided cost generally refers to the cost the utility avoids when buying power from another entity rather than generating the power itself. Under the Public Utility Regulatory Policy Act of 1978 ("PURPA"), payments made to qualifying facilities for power are based on avoided cost rates. In the DER program context, S.C. Code §58-39-140(A)(1) states that "avoided cost" for purposes of separating total DER program costs between incremental and avoided costs is "all costs paid under avoided cost rates, or negotiated rates pursuant to PURPA, which ever is lower". In S.C. Code § 58-139-110(B), avoided costs are further defined, indicating that they are to be rates most recently approved by the Commission, or negotiated pursuant to PURPA.

Q. WHAT INCREMENTAL AND AVOIDED COSTS ARE INCLUDED IN THE COMPANY'S PROPOSAL IN THIS PROCEEDING?

A. Smith Exhibit Nos. 1 and 2 depict the DER incremental and avoided costs that the Company expects to incur during the forecast and billing period, applicable to the fuel component of its base rates, as well as costs incurred during the review period.

DEC's DER incremental costs include the following categories of costs:

- Costs associated with purchase power agreements ("PPA") in excess of the Company's avoided cost rate;
- The DER net energy metering ("NEM") Incentive, which is a credit available to eligible NEM customer-generators, approved in Docket No. 2014-246-E;
- Avoided capacity costs associated with NEM, recoverable as an incremental cost based on Section 58-40-10(F)(6);
- Rebates given to residential and non-residential customers to invest in or lease distributed generation and carrying costs related to the amortization of the rebate amounts;

- A subsidy utilized to lower the subscription charge customers will pay to participate in a Shared Solar program;
- General and administrative costs, which include the cost of developing and implementing programs, cost of incremental labor and additional revenue-grade meters.

DEC's avoided costs include the following categories of costs:

- Amounts paid under avoided costs rates or rates negotiated pursuant to Public Utility Regulatory Policy Act of 1978 ("PURPA") for purchased power agreements;
- Amounts paid for the purchase of power from participants in the Solar Rebate and Shared Solar programs at the Company's avoided cost rates.

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE AND RECOVER ITS INCREMENTAL COSTS?

A. S.C. Code § 58-27-865 (A)(1) states that the incremental and avoided costs of DER programs and NEM shall be allocated and recovered based on the same method that is used by the utility to allocate and recover variable environmental costs. The same section of the statute referenced above prescribes that all variable environmental costs included in fuel costs shall be recovered from each class of customers as a separate environmental component of the overall fuel factor. The specific environmental component for each class of customers shall be determined by allocating such variable environmental costs among customer classes based on the utility's South Carolina firm peak demand data from the prior year. Further, S.C. Code § 58-39-150 sets an annual amount per account limit (or cap) on costs incurred and recovered from residential, commercial and industrial classes.

Q. HOW DOES DEC ALLOCATE AND RECOVER ENVIRONMENTAL COSTS?

A. Environmental costs are allocated to Residential, General Service/Lighting, and Industrial rate classes based upon the firm peak experienced in the prior year. Rates for each class are designed based on costs allocated to the respective rate classes and the projected energy consumption in kilowatt-hours ("kWh").

Q. HOW DOES DEC PROPOSE TO ALLOCATE AND RECOVER DER INCREMENTAL COSTS?

A. DEC proposes that 100% of DER incremental costs be allocated to Residential, Commerical (General Service/Lighting), and Industrial rate classes based upon the firm peak of each class for the prior year. For recovery purposes, each class's allocated portion of incremental costs will then be divided by the number of accounts subject to DER in each class. This method results in an annual dollar per account charge for all accounts subject to DER in each class. The annual charge is a fixed monthly charge added to the fuel factor for each class of customer.

One exception to this approach is the allocation of the avoided capacity cost associated with NEM that is included in the DER incremental costs. This particular incremental cost has been allocated to South Carolina retail based on its pro rata share of system peak demand, rather than 100%. This DER cost is related to system generation supply resources. Costs and benefits associated with system generation supply resources are traditionally allocated among all of the Company's rate jurisdictions since such generation supply resources are operated as a portfolio to serve its native load customers in all rate jurisdictions.

Q. DEC IS PROPOSING TO RECOVER ITS DER INCREMENTAL COSTS THROUGH A PER-ACCOUNT CHARGE ALTHOUGH ITS VARIABLE ENVIRONMENTAL COSTS ARE NOT RECOVERED IN SUCH A MANNER. PLEASE EXPLAIN WHY DEC IS MAKING THIS PROPOSAL.

A. The Company believes this is the best way of ensuring that the statutory cost caps are not exceeded. As noted above in my testimony, DEC proposes that the allocated portion of incremental DER charges for each customer class will be billed to customers on a dollar per-account basis, since such charges are capped on a per-account basis. The recovery of DEC's variable environmental charges are not capped in such a manner. The Company believes that the per-account recovery approach is appropriate since S.C. Code § 58-27-865 does not prescribe a particular billing unit for costs recovered under this section and the Commission has historically approved different options, both rates per kWh and rates per kW. The per-account caps have been established based on class groupings of Residential, Commercial and Industrial; these groupings conform with the firm peak demand allocator groupings historically used by DEC.

Also, although the Company is proposing to recover its incremental costs through a per-account charge, it is important to note that it will recover its avoided costs in the exact same manner as its variable environmental costs. The allocated portion of avoided cost DER charges for each customer class will be billed to customers using a per-kWh rate for Residential, General Service/Lighting, and Industrial customers, consistent with historical practices for billing environmental costs, since these cost are not subject to the per-account caps.

Q. CAN YOU ELABORATE ON WHY A PER-ACCOUNT CHARGE IS A MORE APPROPRIATE MECHANISM TO RECOVER THE COMPANY'S DER INCREMENTAL COSTS?

A. There are several reasons why the Company believes that the best approach is to establish a charge per account to recover DER incremental costs. First, by establishing the charges for incremental DER costs as a dollar per account, the amount customers pay for DER incremental program costs will be transparent; it will be clear that the approved rates will not result in charges in excess of the statutory cap. For example, if incremental costs allocable to residential customers are about $2.5 million, and the charge per residential account is $5.28 per year, or $0.44 per month, customers have price certainty related to DER charges and can clearly know that the $12 per year cap has not been exceeded. However, if the DER costs of $2.5 million are recovered as a rate per kWh, the rate would be 0.0375 cents per kWh. In this circumstance, customers would pay a different amount each month for DER incremental costs and would not be able to easily determine how much they are paying each year relative to the statutory cap. Furthermore, under a per-account method, all customers within a class pay the same amount each month and year, which is consistent with a statutory cap based on an account rather than based on energy usage.

However, if the rate is computed on a per kW or kWh basis, and customers pay based on electricity usage, then some customers will pay more than the cap amount for a year and some will pay less than the cap amount. To avoid this situation, the Company's billing system would need to be able to monitor the billing of an individual component embedded in customer rates for each customer account and stop the billing of that component at the point that the annual cap is reached. This type of billing scenario is quite outside the parameters of typical utility billing system functions, since rates are historically either a per kWh charge with no cap (such as an energy rate), a per kW charge with no cap (such a demand rate) or a fixed dollar amount (such as a basic facilities charge). If the Company is required to reconfigure its billing systems to be able to handle capping a charge that is embedded in the company's demand and energy rates, in addition to the significant time and expense to modify the billing system, another issue is created related to under collection of incremental costs. If the DER incremental charge is collected as a rate per kWh or kW, and the billing system is modified to be able to stop billing the charge when the cap is met, then the Company may routinely be in a situation in which it will under-recover its costs. This occurs because when a volumetric rate is set by dividing the cost assigned to the class by the expected kW or kWh usage of the class, it is inherently assumed that a charge will be assessed on all of the expected kW or kWh usage. However, for customers that use more than the average kW or kWh usage of the class, the cap will be reached mid-year and billings must be discontinued. In this situation, the Company will under collect since the established rate anticipated that <u>all</u> kW or kWh usage could be assessed the rate per unit.

Using a very simplified example shown in the table below, assume the Company has only 2 residential accounts that can be billed up to $12 per year for DER incremental costs for a total of $24. Total residential sales are expected to be 48,000 per year, with Customer A using 12,000 kWh and Customer B using 36,000 kWh. The Company spends $19.20 in a year for DER incremental programs costs. Incremental cost of $19.20 divided by sales of 48,000 kWh produces a rate per kWh of $0.0004. In this case Customer A only 12,000 kWh and will pay $4.80; well under the $12 per year cap. However, Customer B uses 36,000 kWh in a year the amount charged must be capped, as the $14.40 charge would exceed the cap of $12 per year. As shown in the table below, using a rate per kWh, the Company would be unable to recover $2.40 of incremental cost because the cost cap would be reached for Customer B once the customer reached 30,000 kWh usage during the year.

	Residential Class				
			Account A	**Account B**	**Total**
1	Number of accounts	input	1	1	2
2	Incremental cost incurred	input			$ 19.20
3	Annual kWh usage	input	12,000	36,000	48,000
4	Rate per kWh	Line 2 / Line 3			$ 0.0004
5	Recover cost per kWh usage	Line 3 * Line 4	$ 4.80	$ 14.40	
6	CAP per account SC Code 58-39-150		$ 12.00	$ 12.00	
7	Total recovery limited to CAP	The lesser of Line 5 or Line 6	$ 4.80	$ 12.00	$ 16.80
8	Under Recovery	Total Line7 - Total Line 2			$ (2.40)

Although the amount of under collection created by using a rate per kWh (or per kW) could be carried forward to a future period, the method of charging customers on a per kWh or per kW basis, rather than per account, will continue to result in the same under collection issue each year. The only circumstance in which this under collection problem would not exist is if the amounts spent by the Company for its DER program are significantly less than the total level of expenditures allowed by the customer caps. To remedy this problem, the Company could elect to set the rate by estimating the kWh usage on which the rate could be assessed without exceeding the cap, thus creating a higher rate per kWh that would be applied to fewer kWh. Notably, this approach is a step toward a fixed charge per account because it recognizes that the amount that can be charged to customers is not based on volume, but instead is fixed by the per-account cap.

A better remedy to the issue, though, is to establish the DER incremental charge as a rate per account, rather than rate per kWh, so that the Company would be able to fully collect the $19.20 of cost incurred by collecting $9.60 per customer account, as shown in the remainder of the table below.

			Account A	Account B	Total
9	Recover cost per account	Line 2 / Line 1	$ 9.60	$ 9.60	$ 19.20
10	CAP per account SC Code 58-39-150		$ 12.00	$ 12.00	
11	Total recovery limited to CAP	The lesser of Line 10 or Line 11	$ 9.60	$ 9.60	$ 19.20
12	Under Recovery	Total Line 11 - Total Line 2			$ -

In summary, the Company believes the most equitable, transparent, simple, and timely method of cost recovery is to assess the charges on a per-account basis, consistent with the statutory per-account caps.

Q. ARE THERE ANY COST RECOVERY ISSUES ASSOCIATED WITH THE PRESCRIBED ALLOCATION FACTORS?

A. Yes. The statutory requirement to use a firm peak demand allocator results in the assignment of costs to customer classes in excess of what can be billed to the class under the per-account caps. The cost caps prescribed by law inherently reflect an allocation of costs among customer classes and set an overall "budget" under which the Company must operate. The table below illustrates the allocation among customer classes, on a per-account basis, inherent in the cost caps.

Class	Number of Accounts	Per-account Cap	Capped Cost per Class	Percent to Total	Firm Peak Demand Percentage
Residential	477,347	$ 12	$ 5,728,169	33%	53%
Commercial (General Service/Lighting)	81,512	$ 120	$ 9,781,469	56%	21%
Industrial	1,695	$ 1,200	$ 2,034,454	11%	26%
	560,555		$ 17,544,092	100%	100%

As shown above, the cost cap and the number of accounts implies that the Company can spend a total of $17.5 million in incremental costs to accomplish its

DER program, with 33%, 56% and 11% allocable to the residential, commerical (general service/lighting) and industrial classes respectively. However, the firm peak demand allocation shown in the table allocates the incremental costs among the classes at 53%, 21%, and 26%, respectively, for residential, commercial (general service/lighting) and industrial classes. As a result of this disconnect between the allocations resulting from having a per-account cost cap for costs that must be allocated on the basis of firm peak demand, a portion of the $17.5 million expenditures would be under recovered from Residential customers and Industrial customers due to the cost caps.

Q. PLEASE DESCRIBE HOW DUKE ENERGY CAROLINAS PROPOSES TO ALLOCATE AND RECOVER INCREMENTAL COSTS THAT EXCEED THE PER-ACCOUNT ANNUAL CAPS?

A. In the event the incremental costs to be recovered from any customer class in a given year exceed the per-account annual cost caps set forth in S.C. Code § 58-39-150, the Company proposes to carry forward any such costs in excess of the per-account annual cost caps for recovery, with carrying costs, through the fuel factor as an incremental DER cost in a subsequent year.[1] The total unrecovered costs from all customer classes and interest will be allocated among all customer classes per the firm peak demand method and recovered through the billing factors established for the subsequent year. The unrecovered costs and carrying charges will not be assigned only to the class whose cap resulted in an under recovery.

[1] Consistent with the treatment of uncollected costs within the fuel factor, the Company proposes to include any unrecovered balance in its unbilled revenues with a corresponding deferred debit or credit, the balance of which will be included in the projected DER portion of the fuel cost component of the base rates for the succeeding period.

Q. PLEASE DESCRIBE HOW DUKE ENERGY CAROLINAS PROPOSES TO ALLOCATE AND RECOVER THE AVOIDED COSTS FROM CUSTOMERS?

A. S.C. Code § 58-27-865(A)(1) states that the avoided costs of distributed energy resource programs and net metering shall be allocated and recovered based on the same method that is used by the utility to allocate and recover variable environmental costs. As such, DEC proposes that the South Carolina Retail portion of DER avoided costs be allocated to Residential, General Service/Lighting, and Industrial rate classes based upon the firm peak experienced by each class during the review period. The total cost allocated to each class will be divided by projected sales to arrive at a cents per kWh.

Q. HOW DOES DUKE ENERGY CAROLINAS DEFINE AN ACCOUNT FOR PURPOSES OF THE PROPOSED DOLLAR PER ACCOUNT CHARGES?

A. For purposes of the billing the annual per account charge, Duke Energy Carolinas proposes to apply the charge to each account defined as an “agreement,” or “tariff rate” between Duke Energy Carolinas and a customer, with the exception that certain accounts will not receive the per account charge because of the near certainty that these agreements represent small auxiliary service loads associated with other primary residential, Commercial (general service), or industrial service accounts on which the charge will be assessed. The Company believes that exempting the accounts described above recognizes that the legislation included a provision to limit the impact of DER programs on customer rates by setting a rate cap.

Q. PLEASE DESCRIBE SMITH EXHIBITS 1 THROUGH 5 AND THE EXPECTED IMPACT OF DER PROGRAM COSTS ON CUSTOMERS' FUEL FACTORS.

A. In its next annual fuel proceeding, DEC will incorporate DER program costs into its proposed fuel and environmental cost billing factors. Smith Exhibits 1 through 4 are a mock-up of the types of schedules the Company would expect to include its filing to incorporate the DER program costs.

Smith Exhibits 1 and 2 show the total DER program costs by type of cost incurred, separated into two time periods: (1) June 2014 through September 2015, which represents the review and forecast periods of the annual fuel filing; and (2) October 2015 through September 2016 which represents the billing period of the Company's annual fuel filing. Smith Exhibits 3 and 4 use the DER avoided cost information from Exhibits 1 and 2 to determine the avoided cost amounts that will be allocated among South Carolina retail customer classes and be incorporated into the environmental factors in the next fuel proceeding.

Finally, Smith Exhibit 5 uses the DER incremental cost information from Smith Exhibits 1 and 2 to compute an estimated per-account charge for the billing period, October 2015 through September 2016. Based on current estimates, the per account charges are expected to be well below the per-account cost caps for each class.

Q. WERE SMITH EXHIBITS 1 THROUGH 5 PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

DUKE ENERGY CAROLINAS, LLC
SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
DISTRIBUTED ENERGY RESOURCE INCREMENTAL AND AVOIDED COSTS
ACTUAL AND ESTIMATED COSTS JUNE 2014 - SEPTEMBER 2015

Line No.	Description	Reference	Actual June 2014	Actual July 2014	Actual August 2014	Actual September 2014	Actual October 2014	Actual November 2014
	DER Incremental Costs							
1	Purchased Power Agreements		$ -	$ -	$ -	$ -	$ -	$ -
2	NEM DER Incentive		-	-	-	-	-	-
3	Solar Rebate Program		-	-	-	-	-	-
4	Shared Solar Program		-	-	-	-	-	-
5	Carrying Costs on Deferred Amounts		-	-	-	-	-	-
6	NEM Avoided Capacity Costs		-	-	-	-	-	-
7	NEM Meter Costs		-	-	-	-	-	-
8	General and Administrative Expenses		-	-	-	15,882	19,058	5,959
9	Total DER Incremental Costs	Sum Lines 1 through 8	$ -	$ -	$ -	$ 15,882	$ 19,058	$ 5,959
	DER Avoided Cost - Energy & Capacity							
10	Purchased Power Agreements		$ -	$ -	$ -	$ -	$ -	$ -
11	Shared Solar Program		-	-	-	-	-	-
12	Total DER Avoided Cost	Sum Lines 10 through 11	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Actual December 2014	Actual January 2015	Actual February 2015	Estimated March 2015	Estimated April 2015	Estimated May 2015	Estimated Twelve Months Ended May 2015
	DER Incremental Costs								
13	Purchased Power Agreements		$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEM DER Incentive		-	-	-	-	-	-	-
15	Solar Rebate Program		-	-	-	-	-	-	-
16	Shared Solar Program		-	-	-	-	-	-	-
17	Carrying Costs on Deferred Amounts		-	-	-	-	-	-	-
18	NEM Avoided Capacity Costs		-	-	-	-	-	-	-
19	NEM Meter Costs		-	-	-	-	-	-	-
20	General and Administrative Expenses		5,950	14,156	12,403	146,715	146,715	146,715	513,553
21	Total DER Incremental Costs	Sum Lines 13 through 20	$ 5,950	$ 14,156	$ 12,403	$ 146,715	$ 146,715	$ 146,715	$ 513,553
	DER Avoided Cost - Energy & Capacity								
22	Purchased Power Agreements		$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Shared Solar Program		-	-	-	-	-	-	-
24	Total DER Avoided Cost	Sum Lines 22 through 23	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Estimated June 2015	Estimated July 2015	Estimated August 2015	Estimated September 2015
	DER Incremental Costs					
25	Purchased Power Agreements		$ -	$ -	$ -	$ -
26	NEM DER Incentive		-	-	-	38,998
27	Solar Rebate Program		-	-	-	47,450
28	Shared Solar Program		-	-	-	-
29	Carrying Costs on Deferred Amounts		-	-	-	29,903
30	NEM Avoided Capacity Costs		-	-	-	1,605
31	NEM Meter Costs		-	-	-	2,135
32	General and Administrative Expenses		146,715	146,715	146,715	146,715
33	Total DER Incremental Costs	Sum Lines 25 through 32	$ 146,715	$ 146,715	$ 146,715	$ 266,807
	DER Avoided Cost - Energy & Capacity					
34	Purchased Power Agreements		$ -	$ -	$ -	$ -
35	Shared Solar Program		-	-	-	-
36	Total DER Avoided Cost	Sum Lines 34 through 35	$ -	$ -	$ -	$ -

DUKE ENERGY CAROLINAS, LLC
SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
PROJECTED DISTRIBUTED ENERGY RESOURCE INCREMENTAL AND AVOIDED COSTS
FOR THE 12 MONTHS ENDING OCTOBER 1, 2015 TO SEPTEMBER 30, 2016

Line No.	Description	Reference	*Estimated* October 2015	*Estimated* November 2015	*Estimated* December 2015	*Estimated* January 2016	*Estimated* February 2016	*Estimated* March 2016
	DER Incremental Costs							
1	Purchased Power Agreements		$ -	$ -	$ -	$ -	$ -	$ -
2	NEM DER Incentive		38,998	38,998	38,998	59,243	59,243	59,243
3	Solar Rebate Program		47,450	47,450	47,450	88,068	88,068	88,068
4	Shared Solar Program		-	-	-	-	-	-
5	Carrying Costs on Deferred Amounts		29,903	29,903	29,903	54,393	54,393	54,393
6	NEM Avoided Capacity Costs		1,605	1,605	1,605	2,436	2,436	2,436
7	NEM Meter Costs		2,135	2,135	2,135	3,215	3,215	3,215
8	General and Administrative Expenses		146,715	146,715	146,715	59,615	59,615	59,615
9	Total DER Incremental Costs	Sum Lines 1 through 8	266,807	266,807	266,807	266,969	266,969	266,969
	DER Avoided Cost - Energy & Capacity							
10	Purchased Power Agreements		$ -	$ -	$ -	$ -	$ -	$ -
11	Shared Solar Program		-	-	-	-	-	-
12	Total DER Avoided Cost	Sum Lines 10 through 11	-	-	-	-	-	-

Line No.	Description	Reference	*Estimated* April 2016	*Estimated* May 2016	*Estimated* June 2016	*Estimated* July 2016	*Estimated* August 2016	*Estimated* September 2016	12 Month Total
	DER Incremental Costs								
13	Purchased Power Agreements		$ -	$ -	$ 64,205	$ 64,205	$ 64,205	$ 64,205	$ 256,820
14	NEM DER Incentive		59,243	59,243	59,243	59,243	59,243	59,243	650,181
15	Solar Rebate Program		88,068	88,068	88,068	88,068	88,068	88,068	934,959
16	Shared Solar Program		-	-	25,822	25,822	25,822	25,822	103,286
17	Carrying Costs on Deferred Amounts		54,393	54,393	54,393	54,393	54,393	54,393	579,245
18	NEM Avoided Capacity Costs		2,436	2,436	2,436	2,436	2,436	2,436	26,737
19	NEM Meter Costs		3,215	3,215	3,215	3,215	3,215	3,215	35,343
20	General and Administrative Expenses		59,615	59,615	59,615	59,615	59,615	59,615	976,677
21	Total DER Incremental Costs	Sum Lines 13 through 20	266,969	266,969	356,996	356,996	356,996	356,996	3,563,248
	DER Avoided Cost - Energy & Capacity								
22	Purchased Power Agreements		$ -	$ -	$ 405,915	$ 405,915	$ 405,915	$ 405,915	$ 1,623,660
23	Shared Solar Program		-	-	32,582	32,582	32,582	32,582	130,327
24	Total DER Avoided Cost	Sum Lines 22 through 23	-	-	438,497	438,497	438,497	438,497	1,753,987

DUKE ENERGY CAROLINAS, LLC

SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
DER AVOIDED COSTS - RESIDENTIAL
ACTUAL COSTS JUNE 2014 - JANUARY 2015
ESTIMATED COSTS FEBRUARY 2015 - SEPTEMBER 2015

Line No.	Class	Summer 2013 Firm Coincident Peak (CP) KWs	CP %	Winter 2014 Firm Coincident Peak (CP) KWs	CP %
1	Residential	1,416,784	41.53%	2,101,983	52.76%
2	General Service / Lighting	968,153	28.38%	831,637	20.87%
3	Industrial	1,026,193	30.08%	1,050,479	26.37%
	Total SC	3,411,130	100.00%	3,984,099	100.00%

Residential

Line No.	Description	Reference	Actual June 2014	Actual July 2014	Actual August 2014	Actual September 2014	Actual October 2014	Actual November 2014
4	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -	$ -
5	Total System kWh Sales		7,253,953,030	7,827,730,936	7,495,634,061	7,739,557,665	6,316,852,465	6,190,568,199
6	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 4 / Line 5* 100	-	-	-	-	-	-
7	SC Retail Sales kWh		1,834,122,958	1,942,341,215	1,913,851,869	1,968,033,729	1,583,095,617	1,555,001,635
8	SC DER Avoided Costs - Energy & Capacity	Line 6 * Line 7 / 100	$ -	$ -	$ -	$ -	$ -	$ -
9	Residential DER Avoided Costs Allocated by Firm CP	Line 8 * Line 1	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Actual December 2014	Actual January 2015	Estimated February 2015	Estimated March 2015	Estimated April 2015	Estimated May 2015	Twelve Months Ended May 2015
10	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total System kWh Sales		7,294,601,093	7,612,398,819	7,469,941,715	6,744,168,813	6,279,126,470	6,241,686,637	$ 84,466,219,903
12	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 10 / Line 11* 100	-	-	-	-	-	-	
13	SC Retail Sales kWh		1,798,970,084	1,795,048,968	1,822,938,000	1,669,696,000	1,595,747,000	1,587,739,000	$ 21,066,586,075
14	SC DER Avoided Costs - Energy & Capacity	Line 12 * Line 13 / 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Residential DER Avoided Costs Allocated by Firm CP	Line 14 * Line 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Estimated June 2015	Estimated July 2015	Estimated August 2015	Estimated September 2015	Total Jun'14-Sept'15
16	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -
17	Total System kWh Sales		6,725,561,792	8,047,107,231	8,377,317,683	7,783,870,988	115,400,077,595
18	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 16 / Line 17* 100	-	-	-	-	
19	SC Retail Sales kWh		1,699,747,000	1,997,165,000	2,090,238,000	1,968,014,000	28,821,750,075
20	SC DER Avoided Costs - Energy & Capacity	Line 18 * Line 19 / 100	$ -	$ -	$ -	$ -	$ -
21	Residential DER Avoided Costs Allocated by Firm CP	Line 20 * Line 1	$ -	$ -	$ -	$ -	$ -
22	SC Projected Residential Sales October 2015 - September 2016						6,710,952,000
23	SC Residential Avoided Cost Rate (¢/kWh)						$ -

DUKE ENERGY CAROLINAS, LLC
SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
DER AVOIDED COSTS - GENERAL SERVICE/LIGHTING
ACTUAL COSTS JUNE 2014 - JANUARY 2015
ESTIMATED COSTS FEBRUARY 2015 - SEPTEMBER 2015

Line No.	Class	Summer 2013 Firm Coincident Peak (CP) KWs	CP %	Winter 2014 Firm Coincident Peak (CP) KWs	CP %
1	Residential	1,416,784	41.53%	2,101,983	52.76%
2	General Service / Lighting	968,153	28.38%	831,637	20.87%
3	Industrial	1,026,193	30.08%	1,050,479	26.37%
	Total SC	3,411,130	100.00%	3,984,099	100.00%

General Service / Lighting

Line No.	Description	Reference	Actual June 2014	Actual July 2014	Actual August 2014	Actual September 2014	Actual October 2014	Actual November 2014
4	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -	$ -
5	Total System kWh Sales		7,253,953,030	7,827,730,936	7,495,634,061	7,739,557,665	6,316,852,465	6,190,568,199
6	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 4 / Line 5* 100	-	-	-	-	-	-
7	SC Retail Sales kWh		1,834,122,958	1,942,341,215	1,913,851,869	1,968,033,729	1,583,095,617	1,555,001,635
8	SC DER Avoided Costs - Energy & Capacity	Line 6 * Line 7 / 100	$ -	$ -	$ -	$ -	$ -	$ -
9	General Service/ Lighting DER Avoided Costs Allocated by Firm CP	Line 8 * Line 2	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Actual December 2014	Actual January 2015	Estimated February 2015	Estimated March 2015	Estimated April 2015	Estimated May 2015	Twelve Months Ended May 2015
10	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total System kWh Sales		7,294,601,093	7,612,398,819	7,469,941,715	6,744,168,813	6,279,126,470	6,241,686,637	84,466,219,903
12	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 10 / Line 11* 100	-	-	-	-	-	-	
13	SC Retail Sales kWh		1,798,970,084	1,795,048,968	1,822,938,000	1,669,696,000	1,595,747,000	1,587,739,000	21,066,586,075
14	SC DER Avoided Costs - Energy & Capacity	Line 12 * Line 13 / 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	General Service/ Lighting DER Avoided Costs Allocated by Firm CP	Line 14 * Line 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Estimated June 2015	Estimated July 2015	Estimated August 2015	Estimated September 2015	Total Jun'14-Sept'15
16	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -
17	Total System kWh Sales		6,725,561,792	8,047,107,231	8,377,317,683	7,783,870,986	115,400,077,595
18	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 16 / Line 17* 100	-	-	-	-	
19	SC Retail Sales kWh		1,699,747,000	1,997,165,000	2,090,238,000	1,968,014,000	28,821,750,075
20	SC DER Avoided Costs - Energy & Capacity	Line 18 * Line 19 / 100	$ -	$ -	$ -	$ -	$ -
21	General Service/ Lighting DER Avoided Costs Allocated by Firm CP	Line 20 * Line 2	$ -	$ -	$ -	$ -	$ -

SC Projected General Service / Lighting Sales October 2014 - September 2015	6,095,446,000
SC General Service / Lighting Avoided Cost Rate (¢/kWh)	$ -

DUKE ENERGY CAROLINAS, LLC
SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
DER AVOIDED COSTS - INDUSTRIAL
ACTUAL COSTS JUNE 2014 - JANUARY 2015
ESTIMATED COSTS FEBRUARY 2015 - SEPTEMBER 2015

Line No.	Class	Summer 2013 Firm Coincident Peak (CP) KWs	CP %	Winter 2014 Firm Coincident Peak (CP) KWs	CP %
1	Residential	1,416,784	41.53%	2,101,983	52.76%
2	General Service / Lighting	968,153	28.38%	831,637	20.87%
3	Industrial	1,026,193	30.08%	1,050,479	26.37%
	Total SC	3,411,130	100.00%	3,984,099	100.00%

Line No.	Industrial Description	Reference	Actual June 2014	Actual July 2014	Actual August 2014	Actual September 2014	Actual October 2014	Actual November 2014
4	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -	$ -
5	Total System kWh Sales		7,253,953,030	7,827,730,936	7,495,634,061	7,739,557,665	6,316,852,465	6,190,568,199
6	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 4 / Line 5* 100	-	-	-	-	-	-
7	SC Retail Sales kWh		1,834,122,958	1,942,341,215	1,913,851,869	1,968,033,729	1,583,095,617	1,555,001,635
8	SC DER Avoided Costs - Energy & Capacity	Line 6 * Line 7 / 100	$ -	$ -	$ -	$ -	$ -	$ -
9	Industrial DER Avoided Costs Allocated by Firm CP	Line 8 * Line 3	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Actual December 2014	Actual January 2015	Estimated February 2015	Estimated March 2015	Estimated April 2015	Estimated May 2015	Twelve Months Ended May 2015
10	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Total System kWh Sales		7,294,601,093	7,612,398,819	7,469,941,715	6,744,168,813	6,279,126,470	6,241,686,637	84,466,219,903
12	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 10 / Line 11* 100	-	-	-	-	-	-	
13	SC Retail Sales kWh		1,798,970,084	1,795,048,968	1,822,938,000	1,669,696,000	1,595,747,000	1,587,739,000	21,066,586,075
14	SC DER Avoided Costs - Energy & Capacity	Line 12 * Line 13 / 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Industrial DER Avoided Costs Allocated by Firm CP	Line 14 * Line 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	Estimated June 2015	Estimated July 2015	Estimated August 2015	Estimated September 2015	Total Jun'14-Sept'15
16	Total DER Avoided Costs - Energy & Capacity	Smith Exhibit 1	$ -	$ -	$ -	$ -	$ -
17	Total System kWh Sales		6,725,561,792	8,047,107,231	8,377,317,683	7,783,870,986	115,400,077,595
18	DER Avoided Costs - Energy & Capacity Incurred (¢/kWh)	Line 16 / Line 17* 100	-	-	-	-	
19	SC Retail Sales kWh		1,699,747,000	1,997,165,000	2,090,238,000	1,968,014,000	28,821,750,075
20	SC DER Avoided Costs - Energy & Capacity	Line 18 * Line 19 / 100	$ -	$ -	$ -	$ -	$ -
21	Industrial DER Avoided Costs Allocated by Firm CP	Line 20 * Line 3	$ -	$ -	$ -	$ -	$ -
22	SC Projected Industrial Sales October 2014 - September 2015						8,819,094,000
23	SC Industrial Avoided Cost Rate (¢/kWh)						$ -

DUKE ENERGY CAROLINAS, LLC
SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
CALCULATION OF DISTRIBUTED ENERGY RESOURCE AVOIDED COST PROJECTED RATES
FOR THE 12 MONTHS ENDING OCTOBER 1, 2015 TO SEPTEMBER 30, 2016

Line No.	Class	Summer 2013 Firm Peak KWs	CP %	Winter 2014 Firm Peak KWs	CP %
1	Residential	1,416,784	41.53%	2,101,983	52.76%
2	General Service / Lighting	968,153	28.38%	831,637	20.87%
3	Industrial	1,026,193	30.09%	1,050,479	26.37%
	Total SC	3,411,130	100%	3,984,099	100%

Line No.	Description	Reference	*Estimated* October 2015	*Estimated* November 2015	*Estimated* December 2015	*Estimated* January 2016	*Estimated* February 2016	*Estimated* March 2016
4	Total DER Avoided Costs		$ -	$ -	$ -	$ -	$ -	$ -
5	Projected Total System Sales		6,814,484,537	6,153,855,238	7,052,507,422	8,031,327,947	7,443,247,332	7,153,246,750
6	DER Avoided Costs Incurred (¢/Kwh)	Line 4 / Line 5 * 100	-	-	-	-	-	-
7	Projected SC Retail Sales		1,753,370,000	1,560,167,000	1,726,564,000	1,925,583,000	1,802,214,000	1,760,405,000
8	SC DER Avoided Costs	Line 6 * Line 7 / 100	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Description	Reference	*Estimated* April 2016	*Estimated* May 2016	*Estimated* June 2016	*Estimated* July 2016	*Estimated* August 2016	*Estimated* September 2016	12 Month Total
9	Total DER Avoided Costs		$ -	$ -	$ 438,497	$ 438,497	$ 438,497	$ 438,497	$ 1,753,987
10	Projected Total System Sales		6,388,611,565	6,027,870,182	7,243,326,966	7,861,018,123	8,407,273,314	8,449,981,646	87,026,751,023
11	DER Avoided Costs Incurred (¢/Kwh)	Line 9 / Line 10 * 100	-	-	0.0061	0.0056	0.0052	0.0052	
12	Projected SC Retail Sales		1,613,428,000	1,521,030,000	1,822,667,000	1,932,674,000	2,083,083,000	2,124,307,000	21,625,492,000
13	SC DER Avoided Costs	Line 11 * Line 12 / 100	$ -	$ -	$ 110,341	$ 107,807	$ 108,647	$ 110,237	$ 437,032

Line No.	Description	Reference	October 2015 through Sept 2016
	SC DER Avoided Costs Allocated on CP kWs		
14	Residential	Total Line 13 * Line 1	$ 230,575
15	General Service / Lighting	Total Line 13 * Line 2	$ 91,226
16	Industrial	Total Line 13 * Line 3	$ 115,231
17	Total SC	Sum Lines 14 through 16	$ 437,032
	Projected SC Retail Sales kWh for the 12 month period		
18	Residential		6,710,952,000
19	General Service / Lighting		6,095,446,000
20	Industrial		8,819,094,000
21	Total SC	Sum Lines 18 through 20	21,625,492,000
	SC DER Avoided Costs ¢/kWh		
22	Residential	Line 14 / Line 18 * 100	0.0034
23	General Service / Lighting	Line 15 / Line 19 * 100	0.0015
24	Industrial	Line 16 / Line 20 * 100	0.0013

Smith Exhibit 5
DOCKET NO 2015-55-E

DUKE ENERGY CAROLINAS, LLC
SOUTH CAROLINA DISTRIBUTED ENERGY RESOURCE PROGRAM
PROJECTED BILLING PERIOD INCREMENTAL COST FACTORS
FOR THE 12 MONTHS ENDING OCTOBER 1, 2015 TO SEPTEMBER 30, 2016

	June 2014 through December 2014	January 2015 through Sept 2016	Total Incremental Costs
1 Total DER Incremental Costs	46,850	4,736,903	4,783,753

Allocation of DER Incremental Costs for June 2014- December 2014	Firm Peak Demand - 2013	Total Incremental Costs	Cost Allocated per Firm Peak Demand
2 Residential	41.53%		$ 19,459
3 General/Lighting	28.38%		13,297
4 Industrial	30.08%		14,094
5 Total	100.00%	46,850	$ 46,850

Allocation of DER Incremental Costs for January 2015- September 2016	Firm Peak Demand - 2014	Total Incremental Costs	Cost Allocated per Firm Peak Demand
6 Residential	52.76%		$ 2,499,157
7 General/Lighting	20.87%		988,777
8 Industrial	26.37%		1,248,969
9 Total	100.00%	4,736,903	$ 4,736,903

Total DER Incremental Cost for March 2014 - June 2016	Total Cost Allocated per Firm Peak Demand	Number of Accounts	$ per Account per Year	$ per Account per Month
10 Residential	$ 2,518,616	477,347	$ 5.28	$ 0.44
11 General/Lighting	$ 1,002,074	81,512	$ 12.29	$ 1.02
12 Industrial	$ 1,263,063	1,695	$ 745.17	$ 62.10
13 Total	$ 4,783,753	560,554		